STATE OF NEW MEXICO
DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES
OIL CONSERVATION DIVISION

APPLICATION OF TARGA MIDSTREAM SERVICES, LLC FOR AUTHORIZATION TO INJECT, LEA COUNTY, NEW MEXICO. **CASE NO. 26139**

NOTICE OF SUPPLEMENTAL EXHIBITS

In accordance with the Oil Conservation Division's request at the June 4, 2026 hearing, Targa Midstream Services, LLC ("Targa"), through its undersigned counsel, hereby files the following Supplemental Exhibits:

Exhibit G	**Supplemental Self Affirmed Statement of Paul Ragsdale**
G-1	Final Well Schematic
Exhibit H	**Supplemental Self Affirmed Statement of Jiyue (Jessie) Wu**

Respectfully submitted,

HARDY MCLEAN LLC

/s/ Dana S. Hardy

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Counsel for Targa Midstream Services, LLC

STATE OF NEW MEXICO
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APPLICATION OF TARGA MIDSTREAM SERVICES, LLC FOR AUTHORIZATION TO INJECT, LEA COUNTY, NEW MEXICO. **CASE NO. 26139**

SUPPLEMENTAL SELF-AFFIRMED
STATEMENT OF PAUL RAGSDALE

1. My name is Paul Ragsdale, and I am a consulting drilling engineer for Targa Midstream Services, LLC ("Targa"). I previously submitted a Self-Affirmed Statement in this matter.

2. I am submitting this supplemental statement to provide information requested by Oil Conservation Division ("Division") Technical Examiners at the June 4, 2026 hearing.

A. Tubing Details

3. The detailed tubing and completion information has been incorporated into the well design documentation in the form of a final schematic attached as **Exhibit G-1**. The schematic illustrates the placement, dimensions, and internal diameters of all completion components, including placement and inside diameter of the completion components such as landing nipples, packer and seal assembly details and the Subsurface Safety valve.

B. Openhole Logging

4. Openhole logging considerations have been addressed and will be provided to the Division to characterize the mechanical properties of the injection interval and across the upper and lower confining zones using a Dipole Sonic Log. The resulting data will provide an important basis for validating fracture gradients previously estimated using correlations such as the Eaton method. In addition, these measurements will allow calibration against observed fracture parting pressure derived from step-rate testing. The in-situ stress data will also be valuable to confirm that

Targa Midstream Services, LLC
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Exhibit G

the anticipated abandonment pressure will not result in fracturing of the injection interval or loss of containment via the upper and lower confining zones.

C. Cased Hole Logging

5. Cased-hole logging programs have also been reviewed to ensure proper evaluation of cement integrity and zonal isolation. As requested by the Division, a conventional Cement Bond Log (CBL) in conjunction with a Variable Density Log (VDL) will be used as part of the logging suite. This approach will verify effective isolation of any protected groundwater or aquifer zones.

D. Kill Fluid

6. Hydrostatic calculations that confirm the kill fluid density required to kill the well are set out below: Abandonment pressure is 8773 psi @ 17,347'. A minimum Kill Weight of 9.7 lb/gal is required to kill the well. Using a kill fluid of 10 lb/gal Brine would give a Kill mud weight of 9,020 psi which is adequate to control the well. However, heavier mud is readily available in this area and can be acquired quickly.

7. The chemicals and additives required to mix the kill fluid will include 10 lb/gal brine and is readily available. There are no exotic chemicals, exotic brines, or long-lead times to obtain these items.

8. The attached supplemental exhibits were either prepared by me or under my direction and supervision or were compiled from company business records.

9. I understand that this Supplemental Self-Affirmed Statement will be used as written testimony in this case. I affirm that my testimony above is true and correct and is made under penalty of perjury under the laws of the State of New Mexico. My testimony is made as of the date next to my signature below.

Paul Ragsdale

Paul Ragsdale

06/22/2026

Date

Targa Midstream Services, LLC
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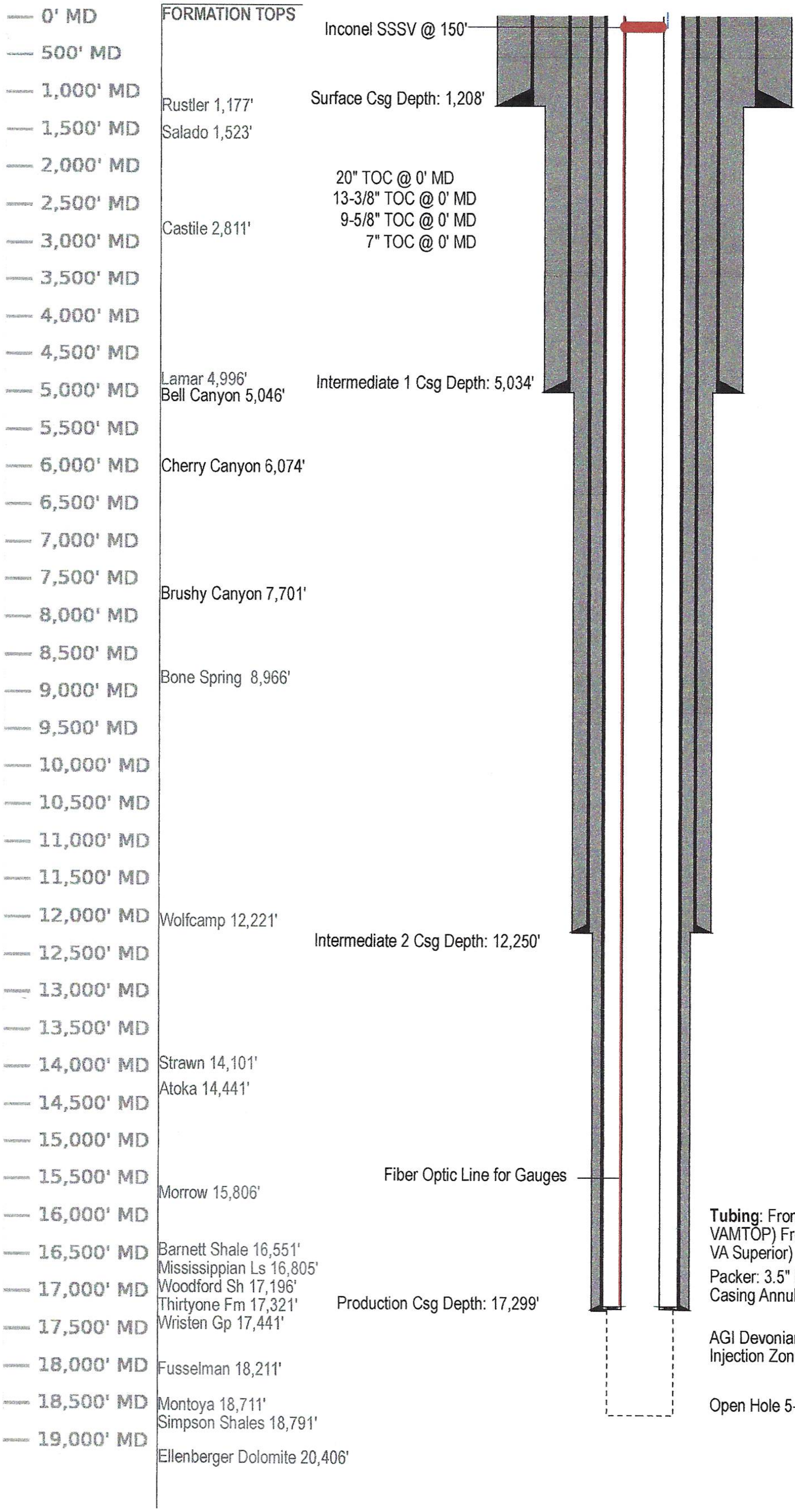
Exhibit G-1

Targa Midstream Services, LLC

COPPERHEAD AGI #002

1,138'FSL & 1,842' FWL Section 13 T24S, R32E
Lea County, New Mexico

Elevation: 3598.21'



Surface Casing
Hole Size: 26"
Casing: 20" 106.5# J-55 BTC
Setting Depth: Surface to 1,028'
Cement: 100% open hole excess 1680 sks lead, 200 sks tail. Volume verified with fluid caliper Lead Class C +2% CaCl2 + 0.25lbl/sk Cello Flake + 0.2% FL, 12.9 ppg, 1.97 cuft/sk. Tail 200 sk Class C 14.8 ppg, 1.34 cuft/sk
Circulate

Intermediate Casing #1 Hole Size: 17.5"
Casing: 13.375" 72# L-80 BTC
Setting Depth: Surface to 5,034' Cement: 75% open hole excess Lead: 1400 sks, Tail: 200 sks CorrosaCem Volume verified with fluid caliper Lead Class C (1450 sks) / Tail CorrosaCem (200 sks) TOC: Surface (Circulated) Lead: Class C Cmt + 3% CaCl + 0.25lb/sk CelloFlake + 5lb/sk LCM, 11.8 ppg 2.453 cuft/sk Tail: CorrosaCem Cmt, 14.5ppg 1.38 cuft/sk

Intermediate Casing #2 Hole Size: 12-1/4"
Casing: 9-5/8 47# L-80 BTC Corrosion Resistant across DMG Cement: Setting Depth: Surface to 12250'
75% open hole excess STAGE 1: Lead 892 sks Tail: 100 sks STAGE 2 Lead: 362 sks CorrosaCem STAGE 3 Lead: 850 sks Tail 200 sks STG 1 Lead: Class C Cmt,12.5 ppg, 1.63 cuft/sk Tail:Class C Cmt 14.82 ppg, 1.32 cuft/sk STG 2: CorrosaCem, 12.0 ppg, 1.75 cuft/sk STG 3: Lead Class C, 12.5 ppg, 1.63 cuft/sk Tail: Class C, 14.8 ppg, 1.32 cuft/sk

Production Casing Hole Size: 8.5" Casing (Upper): 7" 32#

P-110 TUPC (Surface to 16,999') Casing (Lower): 7" 32# GA-110 TCPC (16,999' to 17,299') Cement: 75% open hole excess STAGE 1 600 sacks Corrosion Resistant Cement

STAGE 2 Lead 263 sks Tail 200 sks Volume verified with caliper STG 1: Class H cement 15.6 ppg 600 sacks STG 2: Lead: Class H cement, 12.5 ppg, 1.63 cuft/sk Tail: 200 sks cement, 15.6 ppg, 1. cuft/sk

Tubing: From 17,299 to ~16,950' (3 ½" 9.2# G3 VAMTOP) From 16,950' to surface (3 ½" 9.2# SS-95 VA Superior)

Packer: 3.5" Halliburton 7" Nickel Alloy Permanent Packer set at 17,255'
Casing Annulus fill with packer fluid - diesel and corrosion inhibitors

AGI Devonian Injection Interval
Injection Zone: 17,299' – 18,699'

Open Hole 5-7/8 to **18,699** MD

CoolSky Energy Solutions
05/27/2026 9:00 AM
Version 1.4

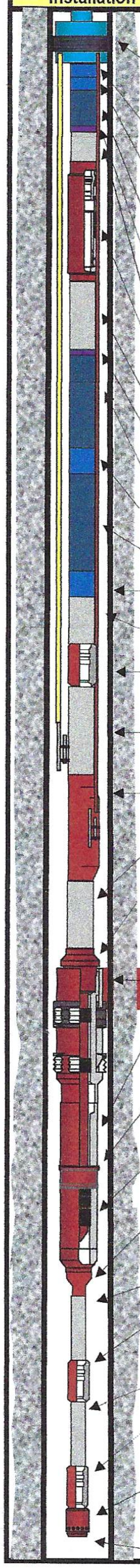
HALLIBURTON

Targa

Copperhead AGI 2
Lea Co. TX
5/14/26 - 5/18/26

Sales Order	910770931
Company Rep.	Brian Baker
Company Rep.	Jake Nave
Tool Specialist	Carey Lehmann

Installation



Installation	Depth	Length	Jts.	Description	OD	ID
	-	25.00		KB ADJUSTED FROM 27' TO 25' DUE TO TUBING HEAD 2' ABOVE GROUND LEVEL		
30	25.00	1.30		30) ATLAS PRESSURE CONTROL 718 INC TUBING HANGER LANDED 35K COMPRESSION BXB 3 1/2" EU TOP / 3 1/2" 10.20# VA SUPERIOR BOTTOM W/ 3" HBPV	11.00	2.950
29	26.30	3.44		29) 3 1/2" 10.20# SS95 VA SUPERIOR INJECTION STRING HANGER HANDLING SUB PXP	3.500	2.922
28	29.74	12.09		28) 3 1/2" 10.20# SS95 VA SUPERIOR INJECTION STRING SPACEOUT SUB	3.500	2.922
27	41.83	124.21	3	27) 3 1/2" 10.20# SS95 VA SUPERIOR INJECTION STRING TUBING	3.500	2.922
26	166.04	1.24		26) 3 1/2" 10.20# T-95 VA SUPERIOR BOX X VAM TOP PIN X/O	4.000	2.898
25	167.28	6.22		25) 6' X 3 1/2" 10.20# T-95 VAM TOP HANDLING SUB W/ COUPLING ON TOP	3.500	2.922
24	173.50	4.25		24) HALLIBURTON TUBING RETRIEVABLE SAFETY VALVE MODEL 'NE' 3 1/2" 10.20# 925NA VAM TOP BXP HAS 2.75" OTIS 'X' PROFILE REF: 103295364	5.300	2.750
23	177.75	6.26		23) 6' X 3 1/2" 10.20# T-95 VAM TOP HANDLING SUB W/ COUPLING ON TOP	3.500	2.922
22	184.01	0.94		22) 3 1/2" 10.20# T-95 VAM TOP BOX X VA SUPERIOR PIN X/O	3.974	2.971
21	184.95	16807.45	410	21) 3 1/2" 10.20# SS95 VA SUPERIOR INJECTION STRING TUBING	3.500	2.922
20	16,992.40	1.40		20) 3 1/2" 10.20# T-95 VA SUPERIOR BOX X VAM 21 PIN X/O	4.020	2.931
19	16,993.80	376.63	10	19) 3 1/2" 9.20# CRA2550 VAM 21 INJECTION STRING TUBING	3.500	2.992
18	17,370.43	1.41		18) 3 1/2" 9.20# 718 INC VAM 21 X VAM TOP BXP X/O	3.950	2.941
17	17,371.84	8.10		17) 8' X 3 1/2" 9.20# CRA2550 VAM TOP TUBING SUB W/ COUPLING ON TOP	3.500	2.922
16	17,379.94	1.33		16) 2.562" OTIS 'R' PROFILE LANDING NIPPLE 3 1/2" 9.20# 925NA VAM TOP BXP REF: 102204262	3.930	2.562
15	17,381.27	8.06		15) 8' X 3 1/2" 9.20# CRA2550 VAM TOP TUBING SUB W/ COUPLING ON TOP HAS FIBER OPTIC CONTROL LINE CLAMPED TO SUB	3.500	2.992
14	17,389.33	4.09		14) HALLIBURTON DATASPHERE OPSIS GAUGE MANDREL WITH TEC LINE TO SURFACE 3 1/2" 9.20# 925NA VAM TOP BXB REF: 103119356	4.750	2.948
13	17,393.42	5.50		13) 6' x 3 1/2" 9.20# CRA2550 VAM TOP TUBING SUB PXP	3.500	2.992
12	17,398.92	0.84		12) 4.00" x 3 1/2" 9.20# 925NA VAM TOP BOX NO-GO LOCATOR SEAL ASSEMBLY WITH SELF ALIGNING MULESHOE GUIDE REF: 103219874 NOTE: 0.84' IS LOCATOR STICKUP ABOVE PACKER HEAD. 22.45' FROM NO-GO TO MULESHOE (SEAL ASSEMBLY IN PACKER BORE)	4.270	2.912
11	17,399.76	3.96		11) 7.00" X 4.00" 23.00-32.00# HALLIBURTON TWA PERMANENT PACKER 925NA 4 3/4-8 UN-2B BOX LOWER CONNECTION REF: 103140971	5.875	4.000
10	17,403.72	9.47		10) 4.00" X 10' SEAL BORE EXTENSION 925NA 4 3/4-8 UN-2B PXP REF:103024118	5.020	4.000
9	17,413.19	0.62		9) SEAL BORE CONNECTOR COUPLING 925NA 4.00" X 4 3/4-8 UN-2B BXB REF: 120053150	5.690	4.000
8	17,413.81	9.48		8) 4.00" X 10' SEAL BORE EXTENSION 925NA 4 3/4-8 UN-2B PXP REF:103024118	5.020	4.000
7	17,423.29	1.10		7) SEAL BORE REDUCER COUPLING 925NA 4 3/4-8 UN-2B X 2 7/8" 6.40# VAM TOP BXB REF: 103055568	5.695	2.402
6	17,424.39	7.83		6) 8' x 2 7/8" 6.40# SM2535 VAM TOP TUBING SUB PXP	2.875	2.441
5	17,432.22	1.16		5) 2.313" OTIS 'R' PROFILE LANDING NIPPLE 2 7/8" 6.40# 925NA VAM TOP BXP REF: 102646012	3.240	2.313
4	17,433.38	8.32		4) 8' x 2 7/8" 6.40# SM2535 VAM TOP TUBING SUB W/ COUPLING ON TOP	2.875	2.441
3	17,441.70	1.42		3) 2.313" OTIS 'XN' PROFILE LANDING NIPPLE W/ 2.205" NO-GO ID 2 7/8" 6.40# 925NA VAM TOP BXP REF: 406943	3.240	2.205
2	17,443.12	0.59		2) 2 7/8" 6.40# SUPER 13CR VAM TOP BOX PUMP OUT PLUG PINNED W/ 6 PINS @ 375PSI/PIN REF: 1195607	3.670	2.400
1	17,443.71	-		1) END OF ASSEMBLY		

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SUPPLEMENTAL SELF-AFFIRMED
STATEMENT OF JIYUE (JESSIE) WU

1. I am a consulting reservoir engineer for Targa Midstream Services, LLC. I previously submitted a Self-Affirmed Statement in this matter.

2. I am submitting this supplemental statement to provide information requested by Oil Conservation Division Technical Examiners at the June 4, 2026 hearing.

A. Equation of State ("EOS") model and parameters.

3. The phase behavior and fluid properties of the Treated Acid Gas ("TAG") stream were characterized using the Peng-Robinson Equation of State ("EOS") in CMG-GEM. The TAG stream was represented using its component composition, including CO2 and H2S, and the EOS input in the GEM fluid model was used to calculate phase behavior and fluid properties during the simulation.

B. Summary table of Treated Acid Gas ("TAG") properties over the life of the well.

4. A summary table of TAG properties over the anticipated life of the Copperhead AGI No. 2 well is provided below. TAG is a compressible fluid, so density and specific gravity vary with pressure and temperature. These properties were evaluated at representative system conditions, including the wellhead, static bottomhole, bottomhole injection, and abandonment conditions. Downhole TAG gas density values were taken from the CMG results where available. The wellhead TAG gas density was calculated separately using the Peng-Robinson EOS at the

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Exhibit H

selected wellhead pressure and temperature because CMG did not directly output actual wellhead gas density.

Node	Pressure (psi)	Temp (degF)	Density (lb/ft3)	Specific Gravity (relative to fresh water)	Comment	NMT Response
Wellhead	2842 (Average WHP for the first two months of injection)	80 (Fixed wellhead temp input)	57.74	0.93	Inlet P & T at the wellhead based upon discharge temperature of 80F at the compression coolers. Wellhead pressure estimated based upon initial reservoir pressure and frictional pressure drop in the tubing during injection at 26 mmscf/d.	CMG calculated injector surface-to-reservoir wellbore pressure drop using the Aziz et al. (1972)[1] correlation and the specified tubing parameters. WHP is a CMG wellbore-model result. The 80°F wellhead temperature is a fixed model input and was held constant during injection. CMG did not directly output actual wellhead TAG gas density. The density reported for this row was calculated separately using the Peng-Robinson EOS at 2842 psi and 80°F, based on the CO2 and H2S composition of the TAG stream.
Bottom hole (static conditions)	7836 (Average BHP from 2067 to 2087)	225 (Fixed bottomhole temp input)	52.04 (Average modeled gas density from 2067 to 2087)	0.83	Static Bottomhole P&T prior to initial injection and/or after a sustained shut-in period.	The static bottomhole condition was represented using the sustained shut-in period after active injection stopped. Pressure and density were calculated as modeled averages from 2067 to 2087, which corresponds to the later post-injection period after the initial shut-in transient had declined. The 225°F temperature is the fixed bottomhole/reservoir temperature input used in the CMG model.
Bottom hole (injection conditions)	7750 (Initial virgin reservoir pressure prior to injection)	225	51.83	0.83	During injection, the bottomhole hole temperature will be below static temperature due to injection of colder fluid (80F) entering the tubing. Assume Pressure is Initial (virgin) reservoir pressure prior to commencing injection.	Pressure was selected as the initial virgin reservoir pressure prior to injection, as requested. The 225°F temperature is the fixed bottomhole temperature input used in the CMG model. The model did not perform a transient thermal wellbore temperature calculation. The density shown was calculated separately using the Peng-Robinson EOS at 7750 psi and 225°F based on the CO2/H2S TAG composition.

[1] Aziz, K., Govier, G.W. and Fogarasi, M., "Pressure Drop in Wells Producing Oil and Gas", JCPT, Vol. 11, (July 1972), pp. 38-48.

Bottom hole (Abandonment conditions)	8773	225	54	0.87	Estimated abandonment pressure based upon the CMG/Petrel reservoir simulation prediction.	Modeled results at end of active injection, immediately before shut-in

C. Clarification of Pressure Constraints and Modeled Pressure Results.

5. The Maximum Allowable Operating Pressure ("MAOP") and bottomhole pressure values stated in the prior hearing exhibit should be understood as operating constraints used in the model setup, not as the maximum pressures predicted by the simulation. The prior exhibit stated that a bottomhole pressure of 10,373 psi was set. This value was a model constraint and was not the modeled maximum BHP result.

6. Based on the updated pressure profiles for the active injection period from 2027 to 2057, the modeled WHP ranges from 2,629 psi to 3,130 psi, with an average of 2,947 psi. The modeled BHP ranges from 8,293 psi to 8,974 psi, with an average of 8,728 psi. The anticipated bottomhole abandonment pressure is 8,773 psi, based on the updated reservoir simulation result at the end of active injection, immediately before shut-in. The anticipated bottomhole abandonment pressure is higher than the initial virgin reservoir pressure of 7,750 psi because reservoir pressure increases during active injection, but it remains lower than the modeled maximum BHP during the active injection period.

Table 1. *Summary of modeled pressure results for the active injection period from 2027 to 2057.*

Time period: 2027-2057	MAX	AVE	MIN
WHP	3130	2947	2629

BHP	8974	8728	8293

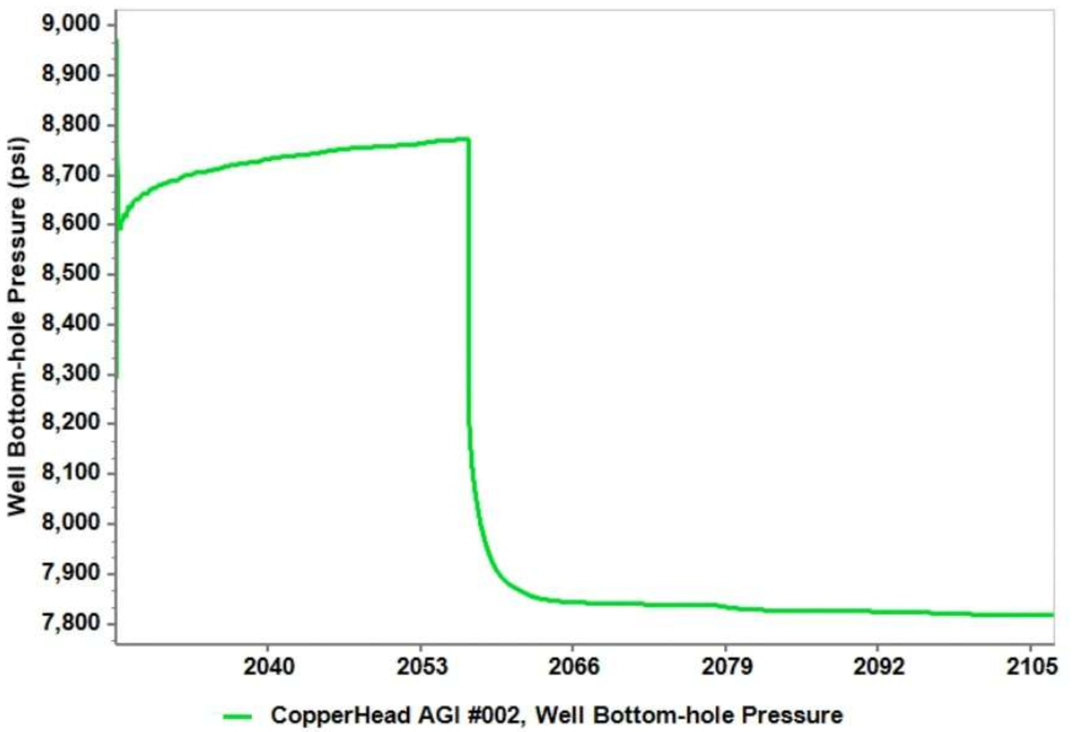

Figure 1. Modeled BHP profile for Copperhead AGI No. 2.

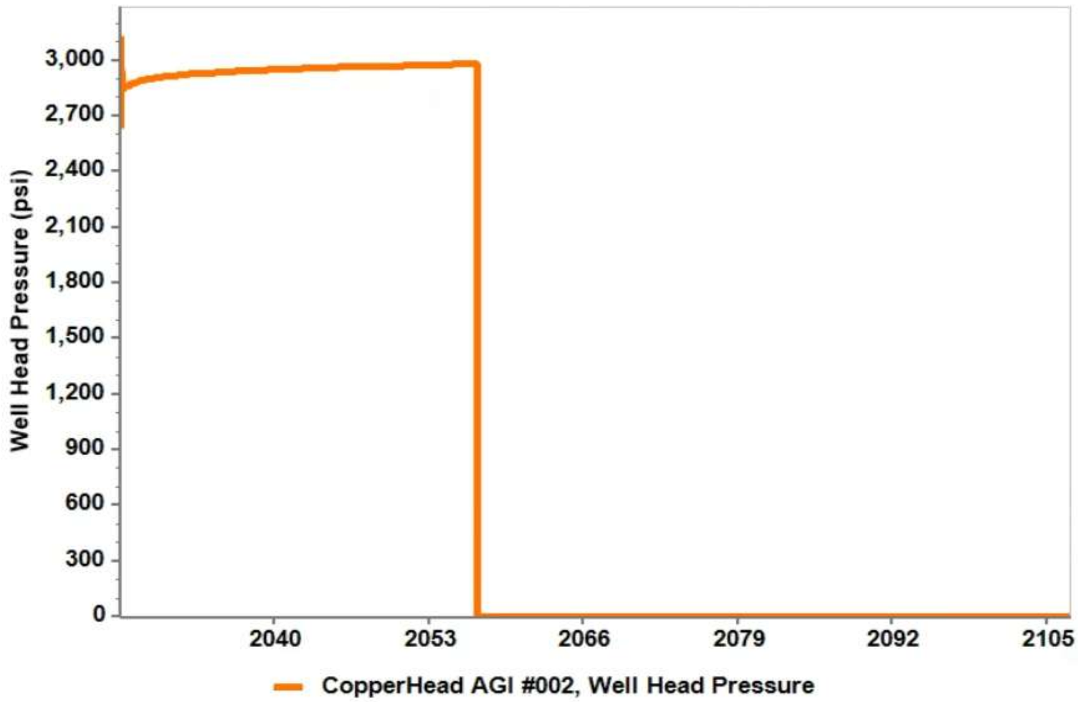

Figure 2. Modeled WHP profile for Copperhead AGI No. 2.

D. Initial Maximum Allowable Operating Pressure.

7. The initial MAOP for the injection well was calculated as follows. For SWD wells, MAOP is determined using the relation MAOP = 0.2 × (depth to the top of the injection interval). However, because TAG has a lower density than typical produced water (assumed to be 1.04), accordingly a modified equation is used as shown below**.** The average TAG specific gravity was defined as the average of the wellhead and bottomhole specific gravity values under initial injection conditions. For example, assuming an injection depth of 13,215 ft and an average TAG specific gravity of 0.804, the calculated MAOP incorporates this correction to ensure an appropriate surface pressure limit that accounts for the fluid density in the tubing. The calculation shown in the red box below is the example calculation to illustrate the method. This methodology provides a technically sound and defensible basis for establishing safe operating conditions for TAG injection.

(Eq. 1) $$MAOP = D_{Top} \times (0.2 + 0.433(1.04 - SG_{tbg,avg}))$$

$$MAOP = 13{,}215 \times (0.2 + 0.433(1.04 - 0.804))$$

$$MAOP = 3{,}994\ psi$$

Where:
D_{Top} – top of injection interval
$SG_{tbg,avg}$ – average TAG specific gravity inside tubing

The average TAG specific gravity inside the tubing was calculated using the wellhead SG and the bottomhole injection SG:

SGtbg,avg = (0.93 + 0.83) / 2 = 0.88

Using DTop = 17347 ft:

MAOP = DTop × [0.2 + 0.433(1.04 - SGtbg,avg)]

MAOP = 17347 × [0.2 + 0.433(1.04 - 0.88)]

MAOP = 4671 psi

8. I understand that this Supplemental Self-Affirmed Statement will be used as written testimony in this case. I affirm that my testimony above is true and correct and is made under penalty of perjury under the laws of the State of New Mexico. My testimony is made as of the date next to my signature below.

______________________ __06/17/2026______________________
Jiyue (Jessie) Wu Date